

Plant Overview

Table I. Plant Performance Summary

Plant Type	PC Subcritical
Carbon capture	Yes
Net power output (kW _e)	549,613
Net plant HHV efficiency (%)	24.9
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 85% capacity factor	118.8
Total plant cost (\$ × 1,000)	\$1,591,277
Cost of CO ₂ avoided ¹ (\$/ton)	68

¹The cost of CO₂ avoided is defined as the difference in the 20-year levelized-cost-of electricity between controlled and uncontrolled like cases, divided by the difference in CO₂ emissions in kg/MWh.

The diagram illustrates the process flow of a pulverized coal boiler system, including air handling, combustion, and emissions control. Key components include the Pulverized Coal Boiler, Baghouse, FGD (Flue Gas Desulfurization), and Econamine FG+.

RAW WATER USAGE

Parameter	Value
Mass Flow, gpm	14,098

AIR

Parameter	Value
Energy Flow, MMBtu/hr	85
Mass Flow, lb/hr	6,481,435

COAL

Rank	Bituminous
Seam	Illinois No. 6
Component	Wt%
Moisture	11.12
Carbon	63.75
Hydrogen	4.50
Nitrogen	1.25
Chlorine	0.29
Sulfur	2.51
Ash	9.70
Oxygen	6.88
Total	100.00

PM/ASH

Parameter	Value
Energy Flow, MMBtu/hr	3
Mass Flow, lb/hr	62,699

INPUT

Parameter	Value
Energy Flow, MMBtu/hr	7,549
Mass Flow, lb/hr	646,589

LOSSES

Parameter	Value
Energy Flow, MMBtu/hr	2,200
Mass Flow, lb/hr	---

OUTPUT

Parameter	Value
Energy Flow, MMBtu/hr	2,359
Mass Flow, lb/hr	---

Net Power 2,359

Net Plant Efficiency, % HHV (Overall) 24.9%

Stack Gas

Parameter	Value
Energy Flow, MMBtu/hr	253
Mass Flow, lb/hr	5,535,170

CO₂

Parameter	Value
Energy Flow, MMBtu/hr	(98)
Mass Flow, lb/hr	1,380,530

FGD

Parameter	Value
Energy Flow, MMBtu/hr	44
Mass Flow, lb/hr	400,501

GYPSUM

Parameter	Value
Energy Flow, MMBtu/hr	0
Mass Flow, lb/hr	146,287

LIMESTONE

Parameter	Value
Energy Flow, MMBtu/hr	0
Mass Flow, lb/hr	146,287

Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The analysis for the subcritical PC plant with CCS is based on a commercially available dry-bottom, wall-fired boiler equipped with low-nitrogen oxides (NO_x) burners (LNBS) and over-fire air (OFA). The unit is a balanced-draft, natural-circulation design equipped with a superheater, reheater, economizer, and air preheater. Hot flue gas (FG) exiting the boiler is treated by a selective catalytic reduction (SCR) unit for NO_x removal, a baghouse for particulate matter (PM) removal, and a limestone-based scrubber for sulfur dioxide (SO₂) control and co-removal of mercury (Hg). This plant utilizes a conventional steam turbine for power generation. The Rankine cycle is based on a single reheat system with steam conditions of 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F).

This subcritical PC plant with CCS is equipped with the Fluor Econamine FG Plus™ technology for carbon capture. Flue gas exiting the scrubber system is directed to the Econamine FG Plus™ process, where CO₂ is absorbed in a monethanolamine-based solvent. A booster blower is required to overcome the process pressure drop. Carbon dioxide recovered in the Econamine FG Plus™ process is dried, compressed, and delivered to the plant fence line at 15.3 MPa (2,215 psia) for subsequent pipeline transport. The compressed CO₂ is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant.

Achieving a nominal 550 MWe net output with this plant configuration results in an HHV thermal input requirement of 2,210,668 kWt (7,543 MMBtu/hr basis). This thermal input is achieved by burning coal at a rate of 646,589 lb/hr, which yields an HHV net plant heat rate of 13,724 Btu/kWh (net plant efficiency of 24.9 percent). The gross power output of 680 MWe is produced from the steam turbine generator. With an auxiliary power requirement of 130 MWe, the net plant output is 550 MWe. The Econamine FG Plus™ process imposes a significant auxiliary power load on the system, which requires this case to have a higher gross output, as compared with the subcritical without CCS case, to maintain the same 550 MWe net output.

Environmental Performance

This study assumes the use of BACT to meet the emission requirements of the 2006 New Source Performance Standard for criteria pollutants.

The subcritical PC plant with CCS has an emission control strategy consisting of LNBS with OFA and SCR for NO_x control, a pulse jet fabric filter for PM control, and a wet-limestone, forced-oxidation scrubber for SO₂ control. After NO_x emissions are initially controlled through the use of LNBS and OFA, an SCR unit is used to further reduce the NO_x concentration by 86 percent. Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent. The wet-limestone, forced-oxidation scrubber achieves a 98 percent removal of SO₂. A polishing scrubber included as part of the Econamine FG Plus™ process further reduces the SO₂ concentration to less than 10 ppmv. The balance of the SO₂ is removed in the Econamine absorber resulting in negligible SO₂ emissions. The byproduct from the wet-limestone scrubber calcium sulfate, is dewatered and stored onsite. The wallboard-grade material potentially can be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit is taken. The combination of SCR, a fabric filter and wet scrubber also

**Table 2. Air Emissions Summary
@ 85% Capacity Factor**

Pollutant	PC Subcritical With CCS (90%)
CO₂	
• tons/year	569,524
• lb/MMBtu	20.3
• cost of CO ₂ avoided (\$/ton)	68
SO₂	
• tons/year	Negligible
• lb/MMBtu	Negligible
NO_x	
• tons/year	1,966
• lb/MMBtu	0.070
PM	
• tons/year	365
• lb/MMBtu	0.013
Hg	
• tons/year	0.032
• lb/TBtu	1.14

provides co-benefit Hg capture at an assumed 90 percent of the inlet value. After leaving the Econamine FG Plus™ process, the flue gas is vented through the plant stack.

A summary of the resulting air emissions is presented in Table 2.

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used as inputs to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 3.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 12.5 percent of the subcritical PC CCS case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 3.6 percent of the subcritical PC CCS case TPC and have been applied to the estimates as follows:

- CO₂ Removal System – 20 percent on all PC CCS cases.
- Instrumentation and Controls – 5 percent on the PC CCS cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for PC cases.

For the PC cases that feature CCS, capital and operating costs were estimated for transporting CO₂ to an underground storage area, associated storage maintenance, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

The calculated cost of transport, storage, and monitoring for CO₂ is \$3.40/short ton, which adds 4.3 mills/kWh to the LCOE.

The 550 (net) MWe subcritical PC plant with CCS was projected to have a TPC of \$2,888/kWe, resulting in a 20-year levelized COE of 118.8 mills/kWh.

Table 3. Major Financial Assumptions and Resulting Cost Summary¹

Major Assumptions			
Case:		1x550 MWe net Subcritical PC with CCS	
Plant Size:	549.6 (MWe, net)	Heat Rate:	13,724 (Btu/kWh)
Primary/Secondary Fuel (type):	Illinois #6 Coal	Fuel Cost:	1.80 (\$/MMBtu)
Construction Duration:	3 (years)	Plant Life:	30 (years)
Total Plant Cost ² Year:	2007 (January)	Plant in Service:	2010 (January)
Capacity Factor:	85 (%)	Capital Charge Factor:	17.5 (%)
Resulting Capital Investment (Levelized 2007 dollars)			Mills/kWh
Total Plant Cost			68.0
Resulting Operating Costs (Levelized 2007 dollars)³			Mills/kWh
Fixed Operating Cost			5.8
Variable Operating Cost			10.8
Resulting Fuel Cost (Levelized 2007 dollars) @ \$1.80 / MMBtu			Mills/kWh
			29.8
Resulting Levelized CO₂ Cost (2007 dollars)			Mills/kWh
			4.3
Total Levelized Busbar Cost of Power (2007 dollars)			Mills/kWh
			118.8

¹Costs shown can vary \pm 30%.²Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.³No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. I, DOE/NETL-2007/1281, May 2007.
B_PC_SUB_CCS_051507